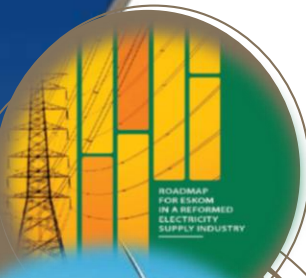


Eskom's 2020_21 proposed retail tariff plan

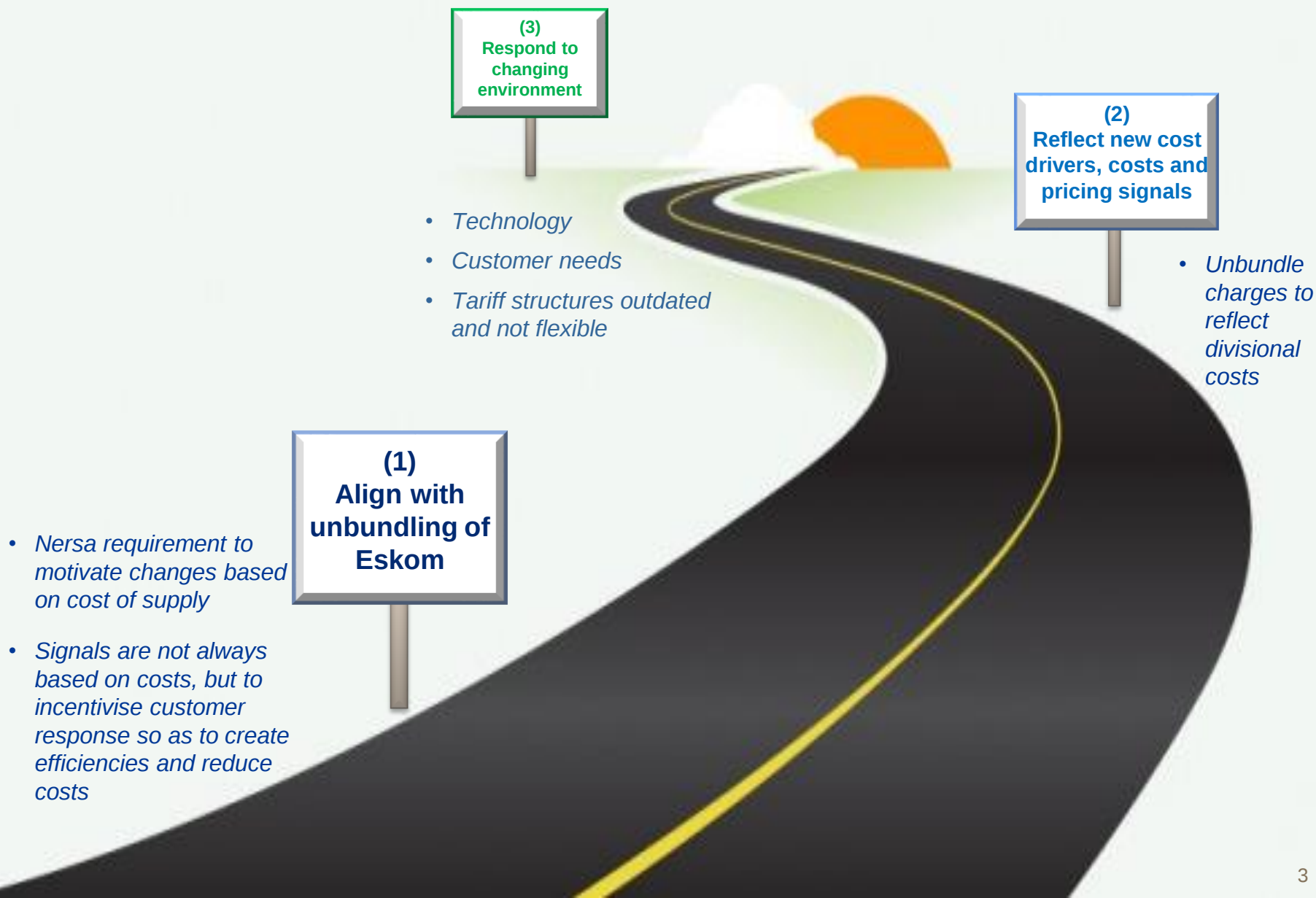


The following are the main objectives of this tariff submission:

- Updating tariffs with the latest cost-to-serve study (CTS)
 - Cost allocation and segmentation, **not** cost justification exercise
- Optimising customer response and use of the system, by revising pricing signals to reflect the current system, and changing TOU rates and times
- Reducing volume risk and increasing fixed charges to reflect fixed costs
- Simplifying tariff options, such as removing IBT and rationalising municipal tariffs
- Providing for more economic recovery of cost-reflective tariffs (structurally)
- Modernising tariff structures in light of evolving customer needs and technology
- *The start of an evolving journey...*



Why are tariff changes being proposed?



1. All rates in this plan are in 2019/20 rand values
2. The rates to be updated to the year of application through the price increase process
3. The aim is that the tariff plan will be approved for implementation 1 April 2021 for non-local-authority tariffs and 1 July 2021 for local-authority tariffs, subject to the Nersa approval process
4. No new supply agreements will be required to be signed where tariffs are restructured or cease to exist and are replaced by a new tariff
5. All changes will be done as far as possible through the billing system

How the tariffs were designed

1. The approved multi-year price determination (MYPD) 2019/20 forecast volumes and cost splits for the three Eskom licensees were used in the CTS and for the design.
 - The tariffs in this submission are reflective of Nersa allowed revenue
 - 2019/20 was used as this was the most recent NERSA-approved values at the time of doing the CTS study
 - The CTS is cost-allocation exercise and not a justification of costs exercise (cost justification is dealt with through the MYPD process) that equitably divides up the approved revenue requirement among the tariff classes.
2. The forecast energy volumes and costs were repacked in the CTS into the restructured TOU volumes.
 - The energy costs comprises the Eskom Generation costs plus the independent power producers (IPP) costs
3. Distribution asset values were updated based on new asset values.
4. Transmission and Distribution loss factors were updated based on representative network studies.
5. At this stage, no changes have been made to the transmission zones for loads.

The proposed structural changes are:

1. Updating all charges using:
 - a) the approved volumes, new cost splits and cost allocation methods based on the 2019/20 Nersa approved revenue requirement and volumes, and
 - b) An updated cost-to-serve (CTS) study
2. Changes to the TOU ratios (peak, standard and off-peak) and TOU periods (swopping peak period and introducing standard period on Sundays) to be aligned to the wholesale rates.
3. Increasing the Distribution fixed charge network charges component weighting, with a commensurate reduction of the variable charge weighting for all tariffs with network charges.
4. Increasing the low voltage charges for Urban LPU – reduces the LV subsidy for larger supplies
5. Removing IBT for Homepower and Homelight,
6. The introduction of a residential time-of-use tariff called Homeflex and plus a new offset rate for those with small scale embedded generation (SSEG)
7. Service charges to be based on number of PODS (points of delivery) and not accounts
8. Rationalisation and combining of the municipal tariffs into only three tariff categories
 - a) a large power version combining Megaflex, Miniflex, Nightsave Urban, Ruraflex and Nightsave Rural into a tariff called Municflex,
 - b) a small power version combining Landrate, Businessrate, and Homepower into a tariff called Municrate, and
 - c) a Public Lighting tariff for non-metered lighting supplies (no change just updated with the CTS).[previously approved in Eskom but not approved by Nersa – required it to be based on a cost to serve study]

Eskom strategic objectives for tariff design

Tariff structures to be more cost-reflective in structure i.e. fixed versus variable charges and in level.

Fixed costs should be recovered through fixed charges

Tariff structures must enable volume risk to be shared between customers and Eskom and allow Eskom and the customer to partner for mutual benefit.

There are currently no penalties or charges for incorrect forecasts provided by customers. Such volume risk lies with Eskom and is only recovered if allowed in the RCA. There needs to be a reward for contracting for volume and moving to recovering fixed costs in fixed charges.

Tariff structures must ensure fair compensation for the use of the grid by generators and loads

Customers with generators are not cross-subsidised by those that don't, but that there is any benefit to the network provider to be passed on to the generator

Tariff structures should incentivise customers to stay connected to the grid.

By making fixed charges too high, this might encourage customers to grid defect. Fair compensation needs to also be provided under a net-billing scheme.

Tariff structures should support sales and adequate recovery of cost

By making tariff structures reflect cost drivers more accurately, this reduces the volume risk and subsequently RCA applications related to changes in volume

Tariff structures should enable better management of demand and supply.

Tariff structures need to reflect more than just costs; they need to provide signals and flexibility for the optimal use of electricity.

What are the economic drivers for tariff changes?



1. Customer Needs

Such as reducing cross subsidies, removing inclining block tariffs (IBT) due to customer unhappiness, accommodating embedded generation, allowing wheeling and flexibility in tariffs.

2. Competition

Such as modernising and updating tariffs to accommodate changes to the way the grid is used due to embedded generation, and also providing wrong economic signals (such as IBT) in light of Small Scale Embedded Generation (SSEG).

3. Smart working

Such as TOU tariffs for residential customers plus an compensating for energy exported (net-billing),

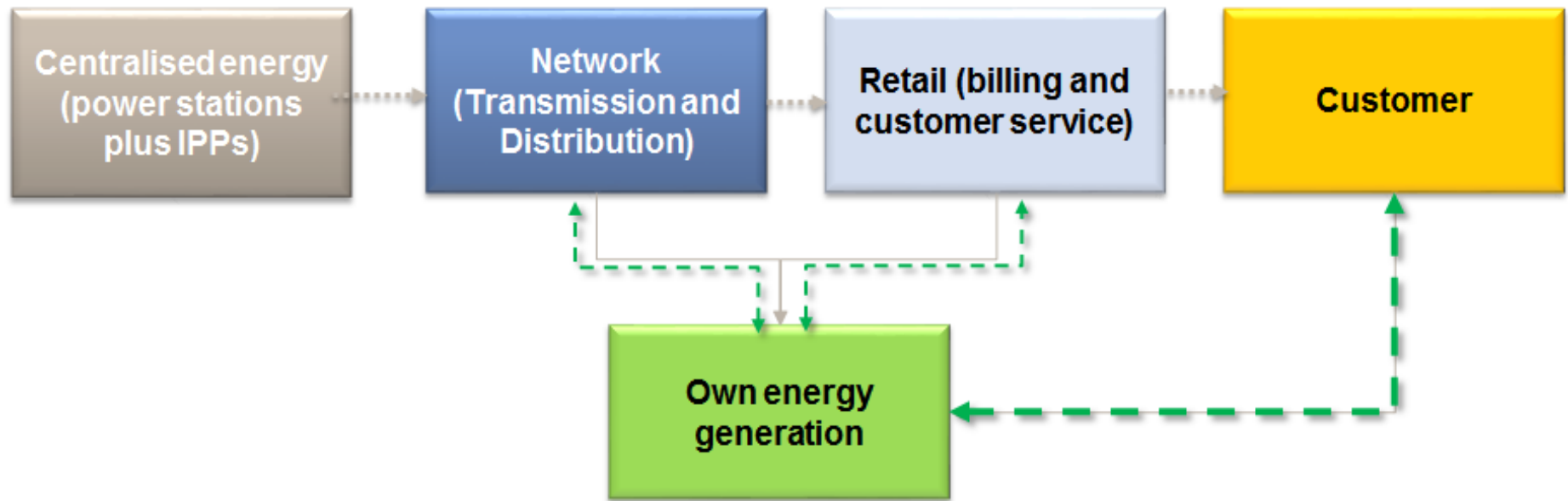
4. Technology and the Green Economy

Such as unbundling tariffs to reflect the changing energy environment impact on network usage, revenue recovery and system usage

5. Efficiency and recovery of costs

Such as tariffs updated to reduce volume risk and to reflect cost causation using the latest cost-to-serve study (cost allocation and segmentation) to more transparently reflect energy, network and retail costs

Example of a driver for change – technology and the green economy



Its important to realise the value of being grid connected and to pay a fair unsubsidised contribution for the use of the grid

1. The introduction of distributed generation results in the **network being used differently** to deliver energy
2. Customers that can afford installing own generation, **still need the grid for stability and back-up** purposes
3. Because tariffs recover both network and energy costs through **volumetric** energy (c/kWh) charges, they no longer reflect the changing energy environment, e.g a residential tariff with only an energy charge of R2/kWh makes alternate energy sources look very attractive. However, only R1 kWh is actually energy and the rest fixed capacity based network costs and retail costs, - should only be competing against R1/kWh and not R2/kWh.
4. The R2/kWh should be **split into network (fixed daily charge) and energy (volumetric c/kWh)**. Does not recover extra revenue – its just splits the charges (rebalances)
5. Will remove artificial subsidies, provide **greater transparency** of costs, ensure the correct economic signal and reflect a **more accurate pay-back period** by comparing energy cost of the utility vs energy cost of the alternate, and not including network cost in the analysis.



-
- | Category | Percentage Change |
|------------------------------|-------------------|
| Energy charges | 14% |
| Transmission network charges | -31% |
| Distribution network charge | -30% |
| Retail charges | -43% |
| LV subsidy charge | -30% |
| ERS and AFS | -53% |
| Affordability subsidy | -65% |
| Ancillary service charges | -50% |

Why network providers should be allowed to make network charges more cost-reflective in structure

1. The grid provides backup, storage and the ability to get compensation.
 - a) Not being connected to the grid means... the customer must have an adequate size generation plant with matching storage capabilities, back up for when the storage is depleted if there is no generation, providing own fault level and no opportunity to get compensation for time of excess.
2. Correct separation and structure of network, retail and energy costs in the tariff charges would provide the correct economic signal and pay-back period for alternate energy decisions by comparing energy cost of the utility vs energy cost of the alternate – energy vs energy.
3. Such changes do not propose to increase the tariffs, but rather to ensure that fair recovery of costs by all so that tariffs more accurately reflect the value of the service being provided.
4. If tariffs are not correctly structured:
 - a) Network costs will become subsidised.
 - b) Tariffs will have to increase. a reduction of sales results in a reduction of the bill on both energy and network charges. This loss in revenue must be recovered then elsewhere as the network costs do not disappear (we don't remove equipment) if there little or no consumption.
 - c) This is not equitable or fair on those that for example would never be able to afford alternate energy sources and does not protect the poor
5. Such changes must **not** be viewed as “anti-renewable” but rather to support the connection of alternate energy resources in a responsible way.

Tariff design process and proposed structural changes



Tariff change process

8) Internal approval, consultation, public hearing and Nersa decision

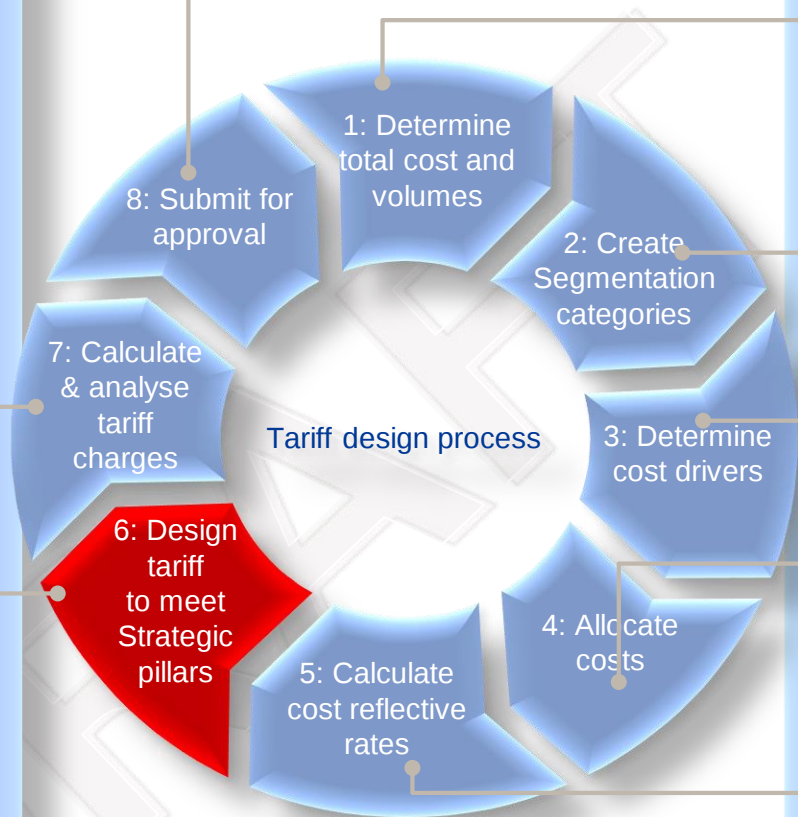
- MFMA and SALGA
- Nersa
- Customers
- Other stakeholders

7) Impact on revenue and impact on customers assessed and changes made if required

6) Tariff design takes place based on strategic objectives and tariff category

- Update on costs
- Changes to tariff structures
- Pricing signals applied
- Charges may be bundled e.g. IBT
- Subsidies applied

Takes into account: national policy and direction (The Electricity Pricing Policy of DoE), Eskom business requirements (Corporate Plan), stakeholder and customers inputs, Regulation (the Electricity Regulation Act, the NERSA Codes, rules and guidelines)



1) MYPD decision on allowed revenue and volumes used in the cost-to-serve study

2) Segment customers based on load factor, size, demand, location and existing tariff

3) Determine the driver of cost e.g kWh, kVA , no. of connection load factor, time of use etc.?

4) Allocate costs and volumes using segmentation and cost drivers

5) Calculate rates per cost driver from the allocated costs

- These are “pure” cost
- reflective and unbundled rates

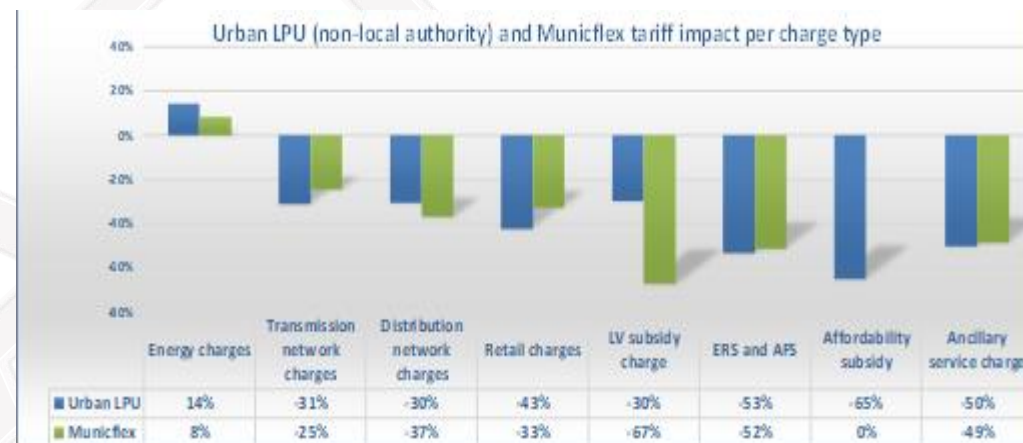
	Energy			Demand	
Tariff	E	S	G	kVA	Customer
Tariff X					
Tariff Y					
Tariff Z					

Cost to serve (or cost of supply study)

Impact of the cost-to-serve on the proposed restructured tariffs

The CTS has impacted the restructured tariffs as follows:

- The MYPD revenue decision per Eskom Division resulting in increases or reductions to energy, networks and retail charges
- Changes to the wholesale TOU periods and rates
- Updated Distribution and Transmission asset values and loss factors based on forecast volumes and revised Distribution loss factors study affecting energy costs and network costs
- Updated customers numbers affecting costs per POD.
- Changes in chargeable demands and utilised capacities affecting network costs per kVA
- Updated Transmission network charges



Proposed changes to TOU rates and periods

	High			Low		
	Weekday	Saturday	Sunday	Weekday	Saturday	Sunday
0	3	3	3	3	3	3
1	3	3	3	3	3	3
2	3	3	3	3	3	3
3	3	3	3	3	3	3
4	3	3	3	3	3	3
5	3	3	3	3	3	3
6	3	3	3	2	3	3
7	3	2	3	3	2	3
8	2	2	3	3	2	3
9	2	2	3	2	2	3
10	2	2	3	2	2	3
11	2	2	3	2	2	3
12	2	3	3	2	3	3
13	2	3	3	2	3	3
14	2	3	3	2	3	3
15	2	3	3	2	3	3
16	2	3	3	2	3	3
17	2	2	2	2	3	3
18	2	2	2	2	2	2
19	3	3	3	3	2	2
20	2	3	3	3	3	3
21	2	3	3	2	3	3
22	3	3	3	3	3	3
23	3	3	3	3	3	3

Proposed changes to the TOU tariffs

- The current TOU charges last changed in 2005 and no longer reflect the current system and customer requirements.
- As a result the current price signals and TOU hours are not optimal for managing the system.
- Therefore it is proposed to 1) change the TOU hours and 2) Change the TOU prices
 - Increasing the evening peak to three hours (from two hours) and reducing morning peak to two hours (from three hours)
 - Introducing a 2 hour standard period on a Sunday evening
 - Reducing the current 1:8 ratio of the summer (low demand season) off-peak rate to the winter (high demand season) peak rate to a 1:6 ratio, and adjusting the rest of the rates commensurately

Current TOU time periods

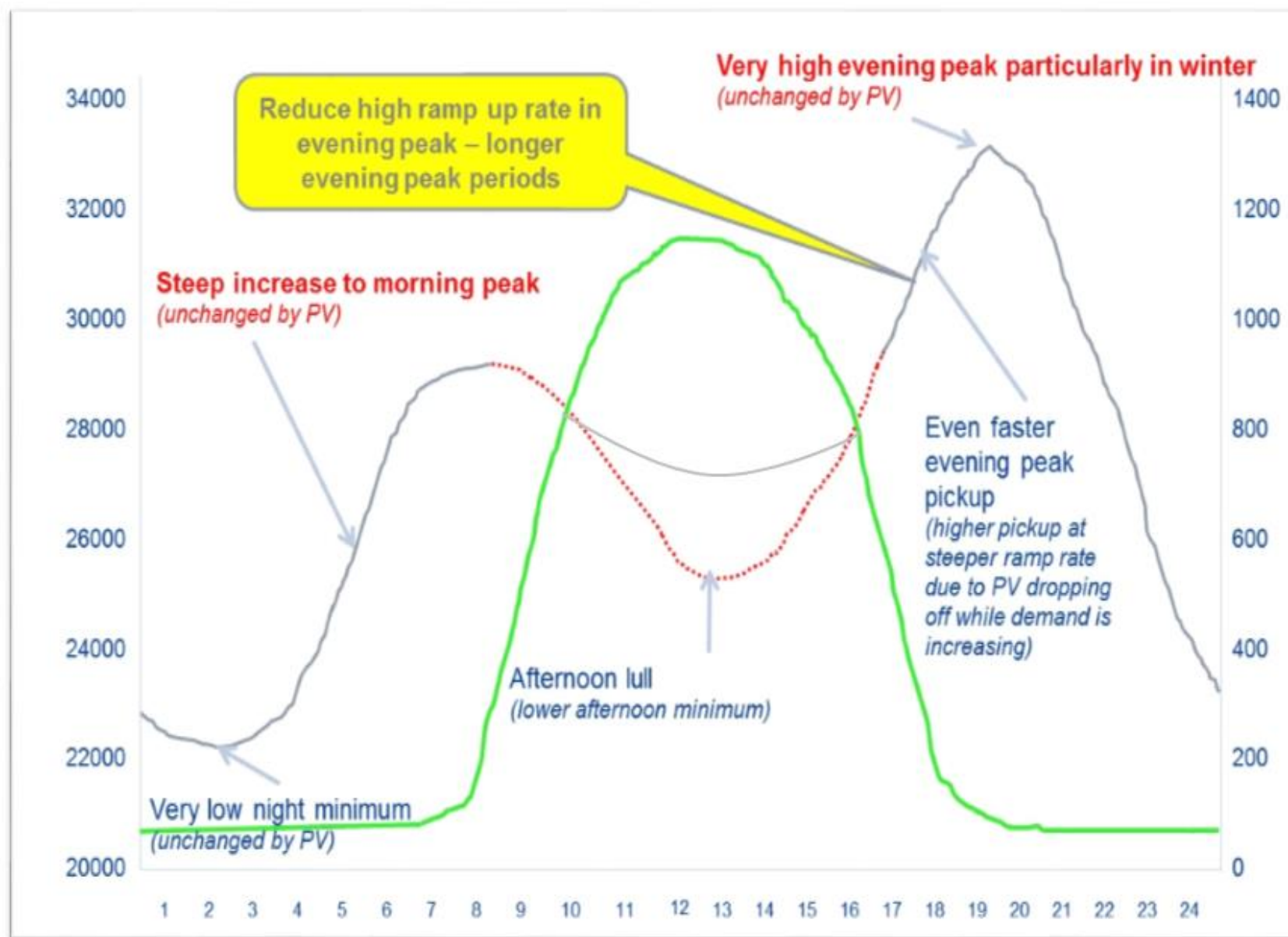
	High			Low		
	Weekday	Saturday	Sunday	Weekday	Saturday	Sunday
0	3	3	3	3	3	3
1	3	3	3	3	3	3
2	3	3	3	3	3	3
3	3	3	3	3	3	3
4	3	3	3	3	3	3
5	3	3	3	3	3	3
6	1	3	3	2	3	3
7	1	2	3	1	2	3
8	1	2	3	1	2	3
9	2	2	3	1	2	3
10	2	2	3	2	2	3
11	2	2	3	2	2	3
12	2	3	3	2	3	3
13	2	3	3	2	3	3
14	2	3	3	2	3	3
15	2	3	3	2	3	3
16	2	3	3	2	3	3
17	1	3	3	2	3	3
18	1	2	3	1	2	3
19	2	2	3	1	2	3
20	2	3	3	2	3	3
21	2	3	3	2	3	3
22	3	3	3	3	3	3
23	3	3	3	3	3	3

Proposed new TOU time periods

	High			Low		
	Weekday	Saturday	Sunday	Weekday	Saturday	Sunday
0	3	3	3	3	3	3
1	3	3	3	3	3	3
2	3	3	3	3	3	3
3	3	3	3	3	3	3
4	3	3	3	3	3	3
5	3	3	3	3	3	3
6	1	3	3	2	3	3
7	1	2	3	1	2	3
8	2	2	3	1	2	3
9	2	2	3	2	2	3
10	2	2	3	2	2	3
11	2	2	3	2	2	3
12	2	3	3	2	3	3
13	2	3	3	2	3	3
14	2	3	3	2	3	3
15	2	3	3	2	3	3
16	2	3	3	2	3	3
17	1	2	2	2	3	3
18	1	2	2	1	2	2
19	1	3	3	1	2	2
20	2	3	3	1	3	3
21	2	3	3	2	3	3
22	3	3	3	3	3	3
23	3	3	3	3	3	3

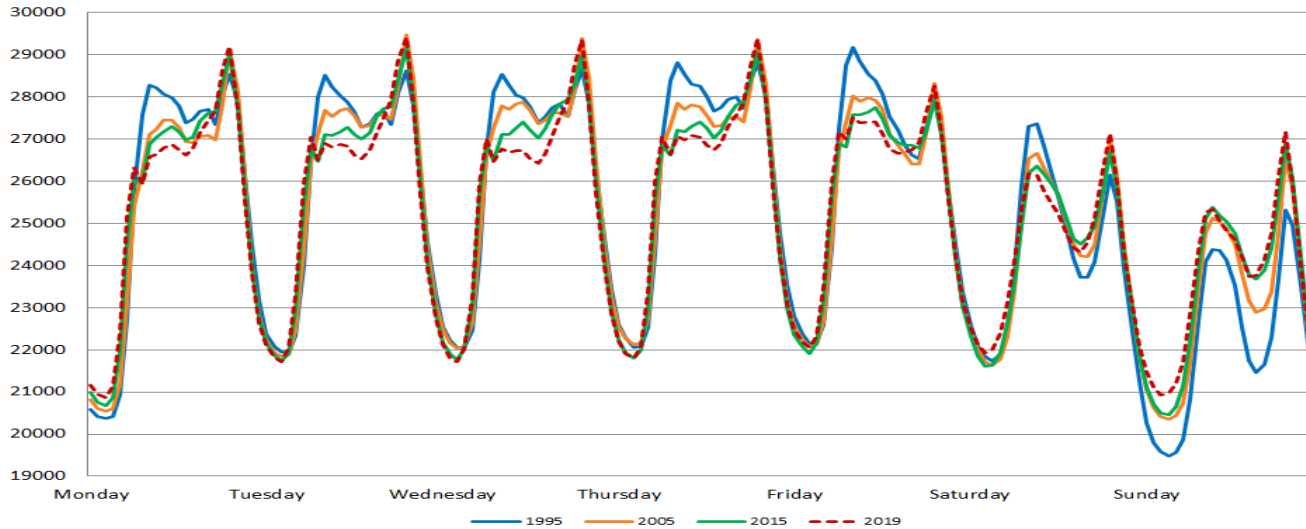
Peak = 1
Standard = 2
Off-peak = 3

System requirement for TOU changes (not to scale)

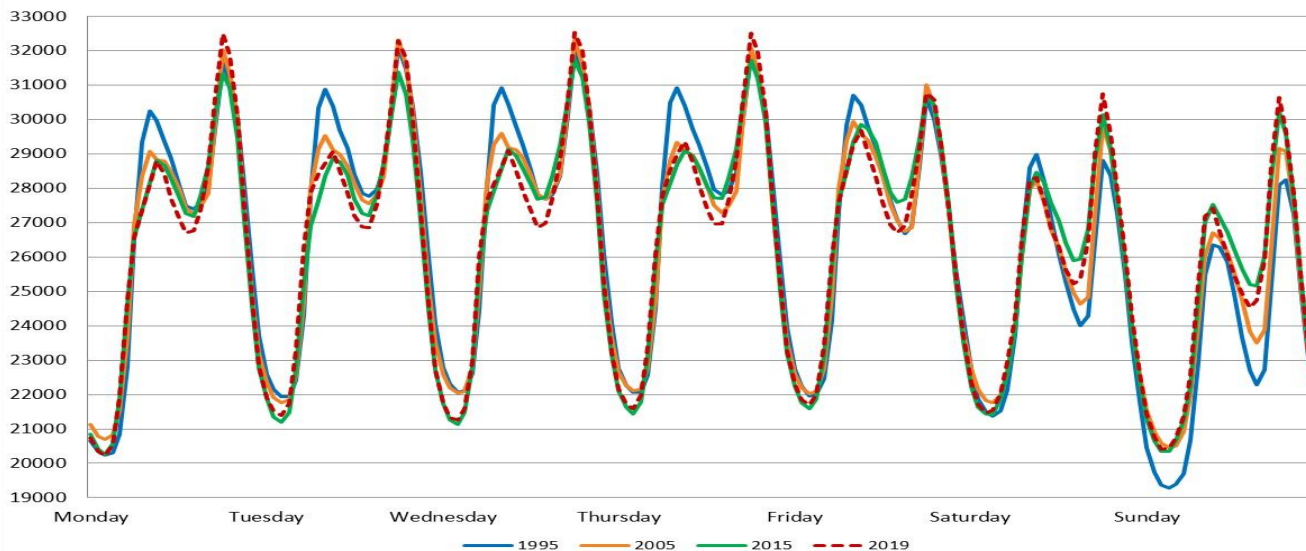


Impact of TOU tariffs over the past 24 years has changed the system profile

Average SCALED Summer Week Profile



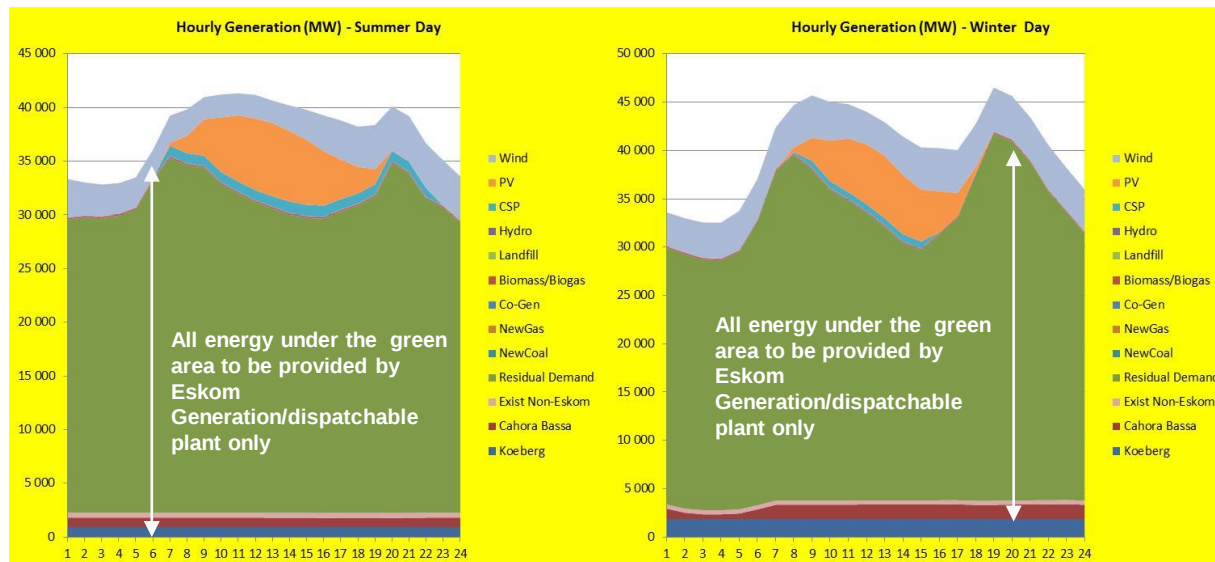
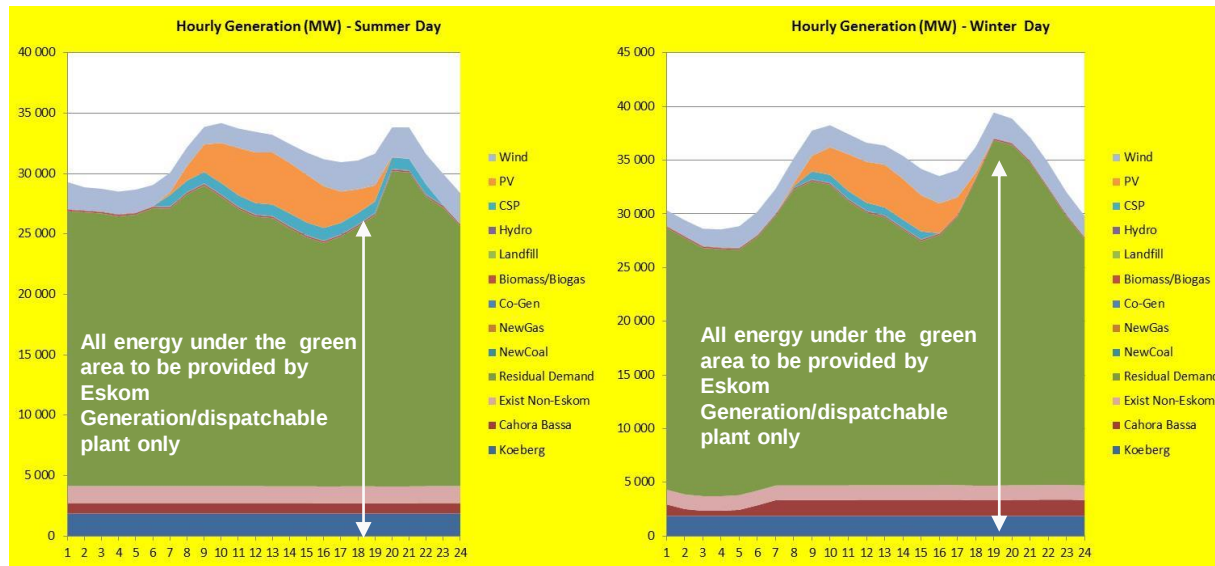
Average SCALED Winter Week Profile (Jun&Jul)



Noticeable changes are:

1. Reduction in morning peak over the years, price signals still needed to manage morning peak
2. Evening peaks both in summer and winter still have very high demand, price signals necessary to manage this demand,
3. Reduction in the Friday evening peaks, and,
4. Increase in the Sunday evening demand similar to weekday. At present, all Sunday hours are off-peak hours. Price signals are necessary to manage the high Sunday evening demand.

Seasonally differentiated TOU price signals to manage morning and evening peaks are still required in future to optimise residual demand



Key points:

1. Renewable energy in national load profile shown in 2025 and 2030, however this energy is not “dispatchable”. Eskom still has to provide the “balance of energy” or “residual demand” (green area and below).
2. Still have morning and evening peaks in the system. Morning and evening peaks are more steeper over time - still have to be managed by price signals.
3. Still a difference in demand level in winter and summer - require different price signals.
4. Drop in mid-day demand is evident; is more pronounced over time, therefore necessary to incentivize consumption to improve system load factor.

New TOU wholesale rates excluding losses

Season Period	High-demand			Low-demand		
	Peak	Standard	Off-Peak	Peak	Standard	Off-Peak
1) Existing ratios	8.00	2.31	1.18	2.50	1.67	1.00
2) Existing WEPS existing TOU ratios c/kWh	296.43	89.79	48.77	96.73	66.55	42.23
3) Updated CTS WEPS existing TOU ratios c/kWh	349.70	100.97	51.58	109.28	73.00	43.71
4) New ratios	6.00	1.50	1.00	2.49	1.40	1.00
5) Existing WEPS new TOU ratios c/kWh	253.40c	63.35c	42.23c	105.16c	59.13c	42.23c
6) Updated CTS WEPS new TOU ratios c/kWh	304.82c	76.20c	50.80c	126.50c	71.13c	50.80c
7) Difference between current and new ratios c/kWh	8.39c	-13.59c	2.03c	29.77c	4.58c	8.57c
8) Difference existing WEPS vs New CTS TOU c/kWh	53.27c	11.18c	2.81c	12.55c	6.45c	1.48c

- This table compares existing WEPS on existing structure, existing WEPS on new structure, existing WEPS structure but based on updated CTS costs and new WEPS structure on updated CTS costs
- The winter peak rate ratio has been decreased from a 1:8 ratio to a 1:6 ratio ([see points 1 and 4](#) above).
- This ratio change before updating the energy costs with the CTS, reduced the winter prices and increases the summer prices ([see points 2 and 5](#) above).
- That all energy rates updated with the CTS energy cost, *before* the ratio change ([see points 2 and 3](#) above) and *after* the ratio changes ([see points 2 and 6](#) above), have been increased.
 - This is due to the application over the years of the average price increase, to the WEPS rates resulting the current energy rates being lower than actual average energy costs.

TOU changes in conclusion

It is a pricing signal to optimise use of the system and is not based on actual costs in each TOU period.
Actual costs vary greatly depending on constraints and surplus for example, its possible that in certain hours summer peak costs might be more expensive than winter peak cost.

To ensure that a load management signal is retained.

To ensure that a strong enough peak price signal is still retained so that expensive generation plant is not used or have capacity constraints are avoided.

That the winter peak price signal is reduced, but still retained when demand is the highest.

To ensure that there is signal to incentivise consumption in periods of surplus

That winter and summer differentials are reduced to respond to customer requests.

To adjust the daily peak to more accurately reflect the current and future peak times – longer and higher evening peak.

Retail charges



How to log a call at Eskom



How to
contact
Eskom

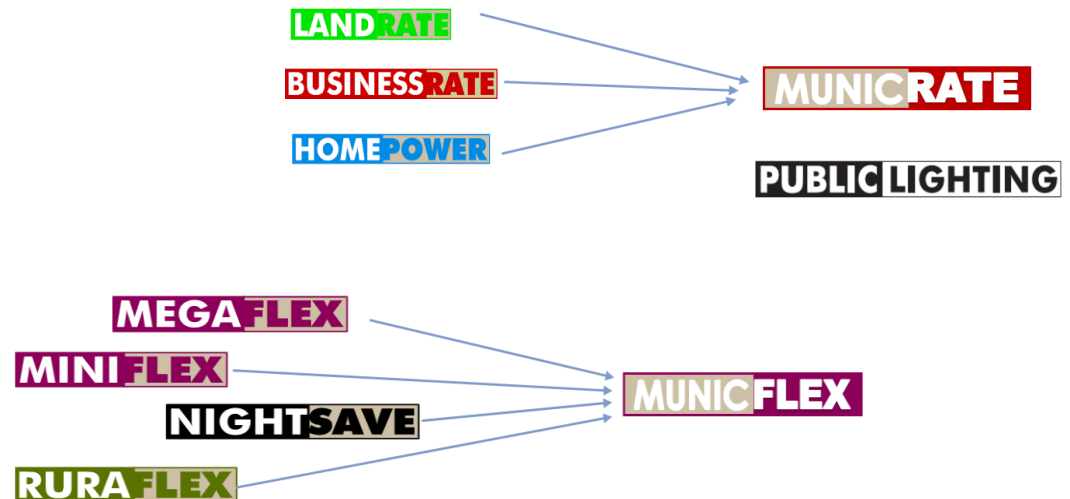


Changes to the retail charges

Retail charge comprise the administration and customer service costs.

- Currently, the administration charge is per point of delivery, and the service charge is per account.
- Eskom proposes changing the methodology so that both the administration charges and the service charges will be per point of delivery and differentiated on size.
- No change is proposed to the current size categories.
- The rationale is that a customer could have many PODs under one account and pay the same service charge as a customer who has one account and one POD. This is not equitable or fair, as more retail resources are used where there are multiple PODs to one account.
- This service charge will not be raised for each transaction separately where the reconciliation of energy is done for wheeling, offset, and banking and where Eskom is the purchaser of energy for generators embedded in a municipality.
- This change will mean that the service charges will decrease in value, but customers who have consolidated many points of delivery into one account may see an overall increase in rates.
- Customers with few PODs per account will see a reduction. This change, however, cannot be viewed in isolation to the other tariff changes as the total impact of all changes will have to be considered.

Municipal tariffs rationalisation



Eskom in November 2017 submitted to Nersa the following:

- To combine Eskom's existing suite of multiple tariffs to municipalities into only three versions:
 - A version based on Megaflex (rates and structure), meaning that Nightsave Urban Large and Small, Nightsave Rural, Miniflex and Ruraflex tariff version would cease to exist
 - A version based on Businessrate (rates and structure), meaning that Landrate and Homepower tariffs versions would cease to exist.
 - No changes to Public Lighting tariff
- In February 2019 Nersa provided Eskom with the following decision

The National Energy Regulator (NERSA), with reference to your correspondence dated 6 November 2017 made a decision on the Eskom's application for the rationalisation of municipal tariffs on the 28 November 2018 as follows:

1. The Energy Regulator decided **not to approve** the Eskom's application for the rationalisation of municipal tariffs for the implementation in the 2019/20 financial year;
2. Eskom should submit the Cost of Supply study (COS) to support the rationalisation. This also needs to justify any cross-subsidisation that must take place.

- Therefore this submission is not based on the principles proposed by Eskom initially above, but on new tariff rates based on the CTS

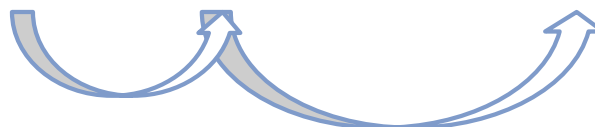
1. A new tariff LPU based on the Megaflex structure, but rates calculated by combining the costs of Megaflex, Miniflex, Nightsave Urban Large and Small, Ruraflex and Nightsave Rural for local-authority supplies
2. A new SPU tariff based on the Business structure, but rates calculated by combining the costs of Landrate, Businessrate and Homepower for local-authority supplies and with the introduction of the ERS charge
3. Public Lighting tariffs based on the cost-reflective CTS results
4. The question of inter-tariff cross-subsidisation is dealt with as the above tariffs are now based on cost, except for the existing socio-economic subsidies
5. The municipal tariff rates in the submission are shown in 12-month values (based on the Eskom financial year April to March), and in 9-month values (based on 3 months April to June current tariffs, 9 months
6. If approved by Nersa, the existing local authority tariffs Megaflex, Miniflex, Nightsave Urban Large and Small, Ruraflex and Nightsave Rural will cease to exist and, be replaced by Municflex
7. If approved by Nersa, the existing local authority tariffs Landrate, Businessrate and Homepower will cease to exist and, be replaced by Municrate

The new tariff options reduce complexity:

- One tariff for large power users.
- One tariff for small power users.
- Public Lighting tariff remains unchanged.
- No longer have an urban/ rural tariff differentiation.
- Will simplify the sales and revenue forecasting process for both Eskom and Municipalities:
- Two tariff options simplify the process of determining the electricity purchase cost for municipalities.

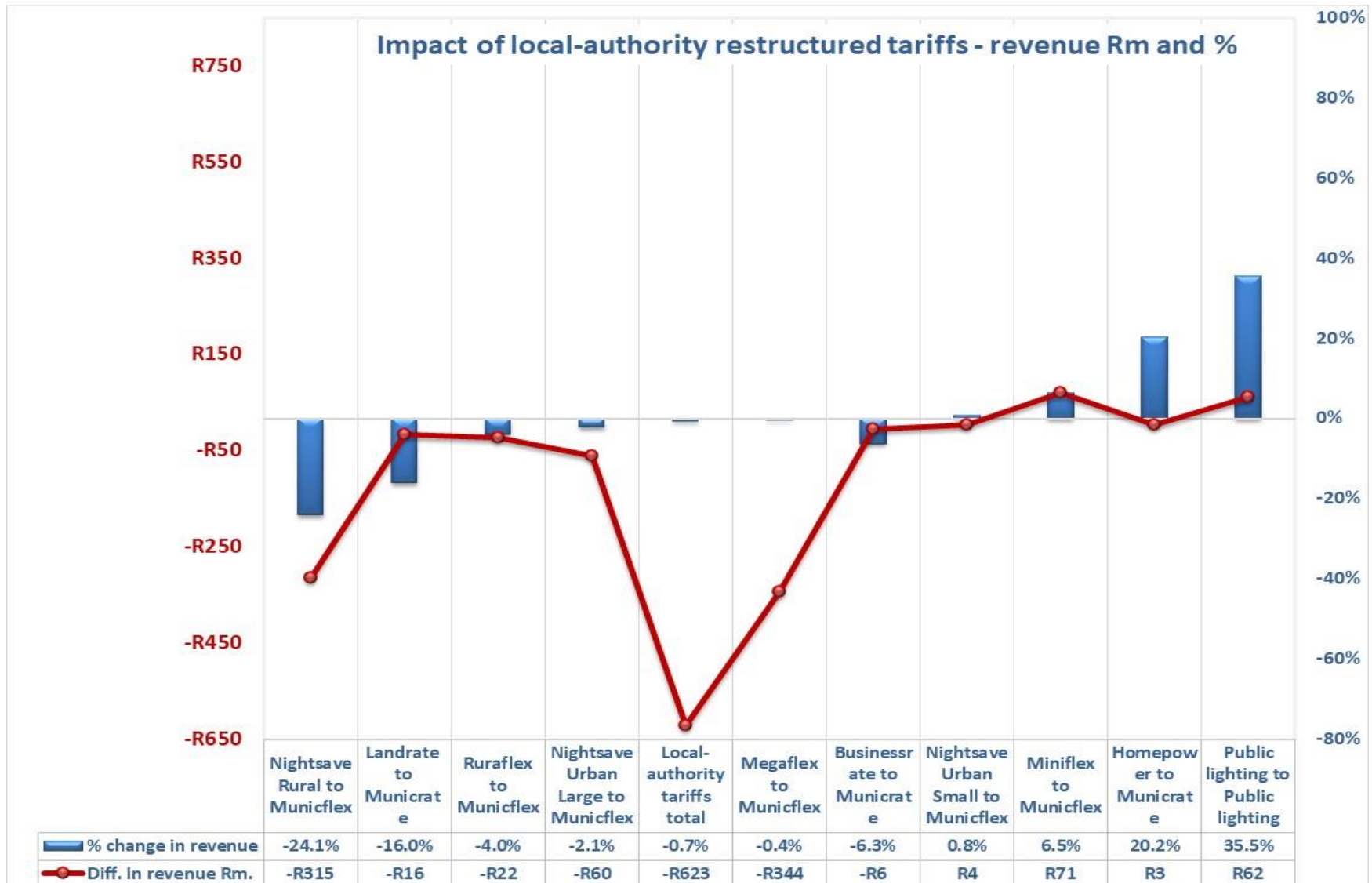
Impact on the restructured local-authority tariffs

Municipal tariffs	CTS allocated allowed costs Rm.	Current tariff revenue Rm.	Diff current tariff revenue and cost	Restructured tariff revenue Rm	Difference new tariff revenue and cost Rm.	Revised subsidy c/kWh	% change in revenue due to restructuring	Difference in revenue Rm. due to restructuring
Local-authority tariffs total	R 82 257	R 86 324	R 4 068	R 85 702	R 3 445	5.95	-1%	-R 623
Megaflex to Municflex	R 75 723	R 79 668	R 3 945	R 79 324	R 3 601	4.49	-0.43%	-R 344
Miniflex to Municflex	R 1 146	R 1 097	-R 49	R 1 168	R 22	2.18	6.50%	R 71
Nightsave Urban Large to Municflex	R 2 709	R 2 813	R 104	R 2 753	R 44	1.77	-2.13%	-R 60
Nightsave Urban Small to Municflex	R 471	R 492	R 21	R 496	R 25	5.95	0.82%	R 4
Ruraflex to Municflex	R 622	R 555	-R 67	R 533	-R 89	(20.03)	-4.03%	-R 22
Nightsave Rural to Municflex	R 1 156	R 1 309	R 153	R 994	-R 162	(18.53)	-24.07%	-R 315
Businessrate to Municrate	R 76	R 100	R 24	R 93	R 17	37.59	-6.30%	-R 6
Landrate to Municrate	R 101	R 99	-R 2	R 83	-R 18	(42.22)	-16.00%	-R 16
Homepower to Municrate	R 16	R 17	R 1	R 20	R 4	43.76	20.21%	R 3
Public lighting to Public lighting	R 237	R 175	-R 62	R 237	R 0.01	0.00	35.50%	R 62



- This table shows cost, the current revenue and the current subsidy compared to the proposed tariffs and revised subsidies
- To be noted is that the contribution to subsidies by local-authority tariffs has reduced

Municipal tariff rationalisation impacts



Impact on local authority tariffs per tariff charge type

Rm impact of changes to rates	Municflex	Municrate	Local-authority Public lighting
Network charge current	R 7 458	R 65	R 0
Network charges proposed	R 6 340	R 67	R 0
% difference	-15%	3%	0%
Energy charges current	R 68 860	R 123	R 175
Energy charges proposed	R 74 613	R 109	R 237
% difference	8%	-11%	35%
Retail charges current	R 215	R 27	R 0.0245
Retail charges proposed	R 144	R 16	R 0.0738
% difference	-33%	-39%	201%
ERS and AS charges current	R 6 977	R 0	R 0
ERS and AF charges proposed	R 3 378	R 4	R 0
% difference	-52%	0%	0%
LV subsidy current	R 2 424	R 0	R 0
LV subsidy proposed	R 793	R 0	R 0
% difference	-67%	0%	0%
Total current	R 85 934	R 215	R 175
Total proposed	R 85 269	R 196	R 237
Difference	-R 666	-R 19	R 62
% Difference	-1%	-9%	36%

Total local authority tariffs
R 7 523.4
R 6 406.7
-15%
R 69 157.7
R 74 959.4
8%
R 242.2
R 160.9
-34%
R 6 977.0
R 3 382.3
-52%
R 2 424.3
R 792.5
-67%
R 86 324.5
R 85 701.9
-R 622.6
-1%

Non-local-authority large power user tariffs

MEGAFLEX

MINIFLEX

RURAFLEX

NIGHTSAVE

Tariff	Change
Megaflex, Miniflex, WEPS	• No structural change. • Energy charges – updated with new TOU ratios and periods. • Network – increasing NCC and commensurate reduction of NDC. • Service charge converted to R/POD.
Transflex	• No structural change. • Energy charges – updated with new TOU ratios and periods. • Service charge converted to R/POD.
Nightsave Urban Large and Small	• No structural change, but Nightsave Small and Large combined (i.e. will now have the same energy demand charges). • Energy charges – updated with new TOU ratios and periods. • Network – increasing NCC and commensurate reduction of NDC. • Service charge converted to R/POD.
Ruraflex and Nightsave Rural	• No structural change, but increases applied to Ruraflex and reduction of Nightsave Rural. • Energy charges – updated with new TOU ratios and periods. • Network charges – increasing NCC and commensurate reduction of NDC. • Service charge converted to R/POD.

Non-local-authority small power user tariffs



Small power use tariffs

Summary of changes per tariff (excl CTS impacts)

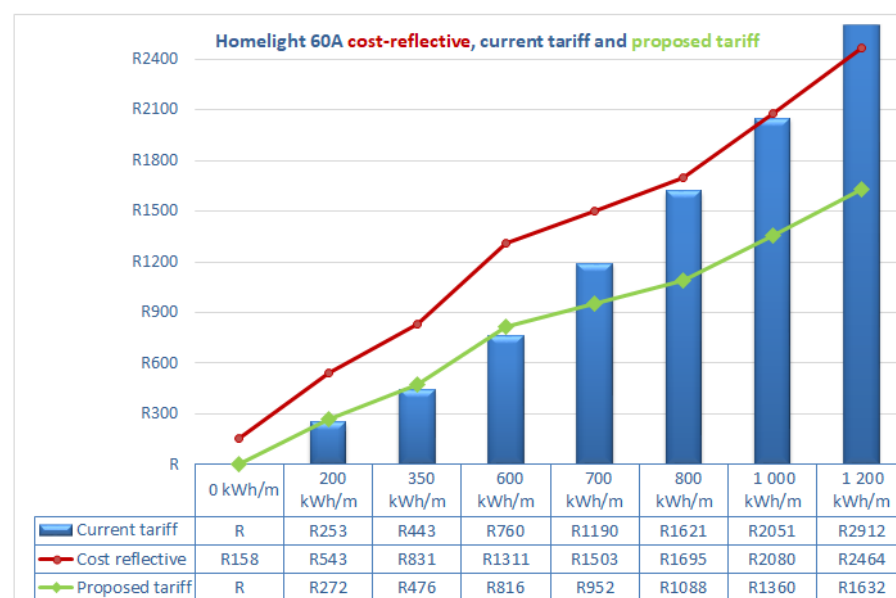
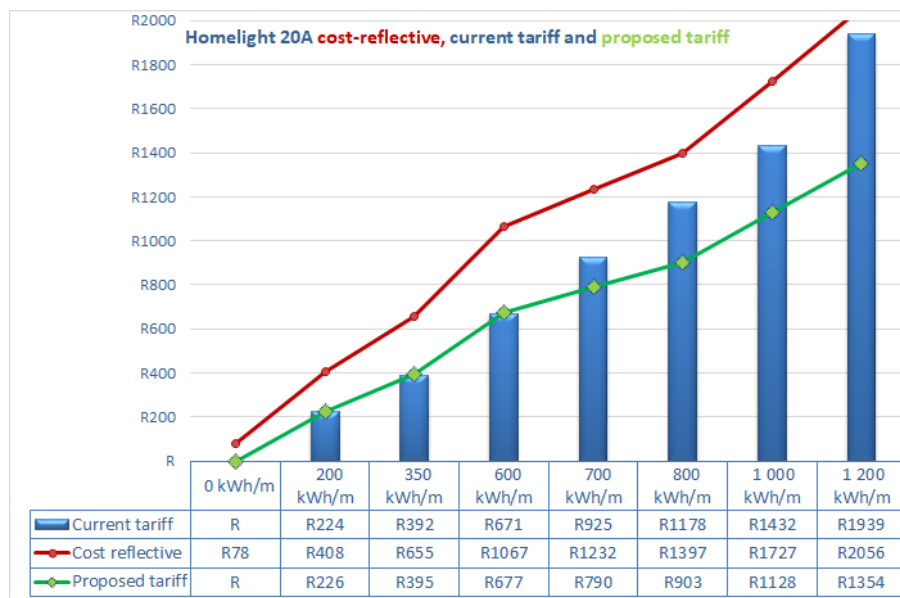
Tariff	Change
Non- municipal	
Businessrate	• Structural change proposed ◦ Introduce Electrification and Rural Network Subsidy (ERS) Charge c/kWh • Network charges – increasing NCC and commensurate reduction of NDC.
Landrate	• No new structure proposed. • Network charges – increasing NCC and commensurate reduction of NDC.
Landlight 20 and 60A	• No structural changes
Homepower	• Structural changes proposed • Removing IBT • Network charges – increasing NCC • Introducing energy charge (c/kWh), ancillary service charge (c/kWh), a network demand charge (c/kWh) and a R/day service and administration charge.
Homelight 20A and 60A	• Structural change proposed ◦ Removing IBT
• Homeflex	• New TOU tariff for energy charges • Same ancillary service charge (c/kWh), a network demand charge (c/kWh) and a R/day service and administration charge as Homepower • Mandatory for grid tied SSEG with offset rate for energy exported (voluntary otherwise)

Homelight changes – removal of the IBT structure

- For the Homelight tariff, the aim is to move away from the IBT structure into a single energy rate structure, based on the average Homelight current revenue/total sales
- No change is proposed to the overall level of subsidies
- Perceptions of IBT
 - Difficult to budget – the more I buy the less I get – or the more I use, the more I pay
 - Does not allow customers to pre-buy for months ahead when money is available (like December bonus)
 - Customers buy legally at the low block and then illegally once they reach the higher block consumption
 - Very confusing and difficult to understand
 - Very unpopular in community discussions
- For large low-income/multiple-family dwellings, it cannot be assumed that low consumption equals poor. In many areas, multiple dwellings may be supplied from a single electricity supply point. An IBT structure has a significant impact on these customers
- By moving away from an IBT structure, there will be an impact in that lower-consumption customers will pay slightly more and higher-consumption customers less

This structural change is revenue neutral to the existing Homelight tariff, that is, recovers the same revenue as the current tariffs and no change has been made to the overall subsidy received. This structural change is not linked to any of the other tariff changes contained in this document as it is not based on cost.

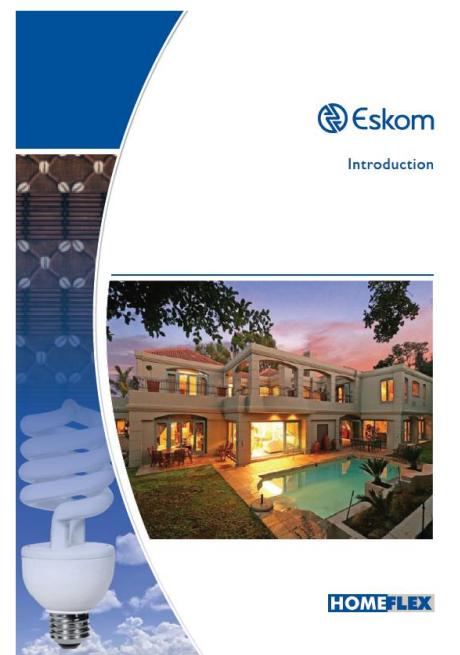
Homelight non-local-authority, proposed vs current



Residential	Cost c/kWh	Tariff c/kWh	Subsidy
Homelight 20A	183.34	112.85	(70.49)
Homelight 60A	204.15	135.98	(68.17)

The level of subsidies remains unchanged with the structural change

Homeflex



Burning platform – why is a net-billing and residential TOU tariff needed?

1. Correcting the economic signal

Non-cost-reflective tariffs (mismatch between cost and tariff)

Current IBT structure is not cost-reflective:

- recovers fixed costs through variable charges;
- no signal for TOU usage/demand, energy capacity and network capacity

Second IBT block rate:

- greatly incentivises higher consumption customers to use solar PV or reduce sales through energy efficiency,
- resulting in a real revenue loss not commensurate with a real cost reduction.

2. Optimising the system

Need to expand TOU to the residential sector to better manage supply and demand and to increase efficiencies in operating cost

SA residential urban customers contribute up to approximately 23%² of the peak demand but do not pay rates that reflect the peak cost – PV also will impact the system profile

Residential TOU provides a market tool to deal with variability of operational capacity

Current IBT has limited signals for the actual demand customers impose on the network

3. Protecting future revenue

Need to position Eskom to have appropriate tariffs for future energy mix i.e. electric vehicles, battery storage and accommodate the **impact of PV** (fixed charges and to ensure that customers with SSEG do not get subsidised by customers without)

DoE has amended Schedule 2 of the Electricity Regulation Act to facilitate registration of SSEG – expect increased SSEG penetration.

Need to get fair compensation for the use of the grid and to also incentive customers to stay connected to the grid.

Current IBT provides no TOU signal and no signal for net-billing – PV for example reduces sales but not peak consumption and peak demand

Research studies estimate revenue lost to PV has been ~R642³ million (2013-2017), projected to increase to ~R3.5 to R4.1 billion by 2021⁴. SA residential PV contribution ~10%

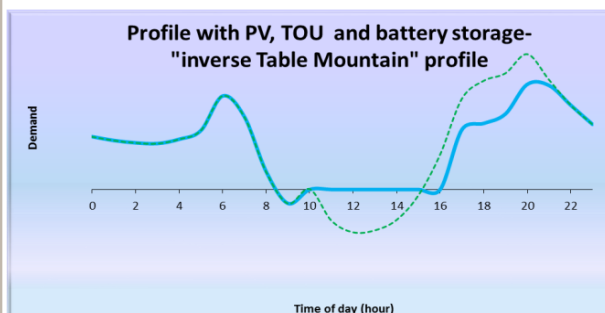
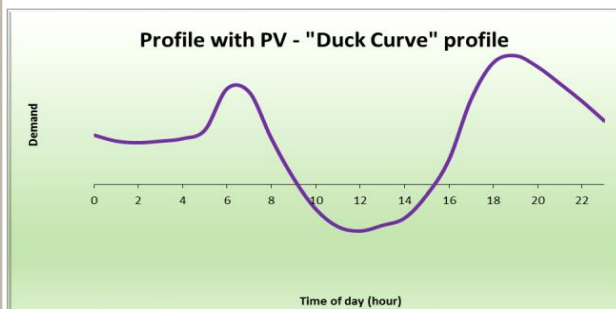
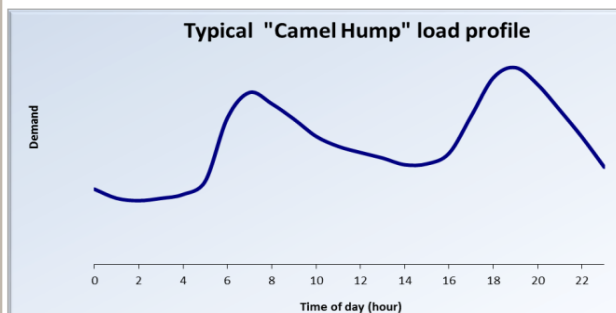
¹ IDM Electrical Usage 2013

² Preliminary Status of Small Scale Solar PV penetration in SA, Aradhna Ramdeyal, RT&D, February 2018

³ Prospects for Small to Medium Scale Solar PV in South Africa: 2017-2020, K Kemper & U Minnaar, March 2018

Burning platform of changing residential profiles

E.g. residential profile



Currently in SA residential customers contribute to 23% demand to the peak period.

- E.g. solar PV **reduces energy consumption by 49%** in summer; peak demand only reduced by **4.9%**¹ (Westar Energy's residential customers in Kansas)

Alters shape of residential load profile i.e. creates the "duck curve"

- Reduces demand middle of the day but not during peak hours,
- PV stops producing just as peak demand is required.

Implications:

- Steep ramp rates during evening peak, requiring use of expensive peaking generation plant, which is uneconomical,
- PV lowers the Generation plant load factor,
- Additional operational costs to serve the peaks are not reflected in current IBT tariffs.

Targeted approach required to achieve reduction in peak demand – change in tariff structure is needed.

- "creating a separate rate class and/or adding a demand charge dimension to rates"

1. Source Do Load Shapes of PV Customers Differ? Implications for Rate Design, Ahmad Faruqi and Walter Graf, Brattle Group
<https://www.fortnightly.com/fortnightly/2018/02/do-load-shapes-pv-customers-differ>

New tariff Homeflex

- Eskom proposes to introduce a residential time-of-use tariff, called “*Homeflex*”, to its’ urban residential customers
- The design of the Homeflex tariff is based on the proposed new TOU structure plus (same as Homepower) network charges, ancillary service charges and service/admin charges
- A net-billing offset rate will be provided for customers with SSEG based on the unbundled energy charge.
- Time-of-use for residential customers is in compliance with the Department of Mineral Resources and Energy’s Electricity Pricing Policy (EPP) policy positions

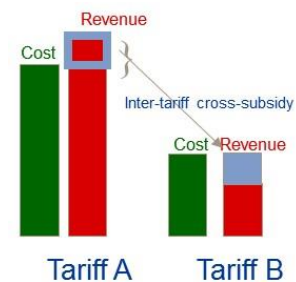
Homeflex	High			Low						
	Peak c/kWh	Standard c/kWh	Off-peak c/kWh	Peak c/kWh	Standard c/kWh	Off-peak c/kWh	Ancillary service charge c/kWh	NDC c/kWh	NCC R/POD/day	Service and admin charge R/POD/day
1	350.77	87.69	58.46	145.57	81.85	58.46	0.2186	15.45	13.74	4.77
2	350.77	87.69	58.46	145.57	81.85	58.46	0.2186	15.45	23.83	4.77
3	350.77	87.69	58.46	145.57	81.85	58.46	0.2186	15.45	58.81	4.77
4	350.77	87.69	58.46	145.57	81.85	58.46	0.2186	15.45	6.53	4.77
Offset rate	350.77	87.69	58.46	145.57	81.85	58.46				

- Customers will have choice to go to Homeflex, but will be mandatory for grid-tied embedded generation (conventional metering only)
- Significant benefits on TOU
 - Can optimise use of own generation and battery storage to reduce bills
 - Can see saving on the bill by reducing peak usage

Why TOU ?

SA residential urban customers contribute up to approximately 23%² of the peak demand but do not pay rates that reflect the peak cost – PV also will impact the system profile

Subsidies



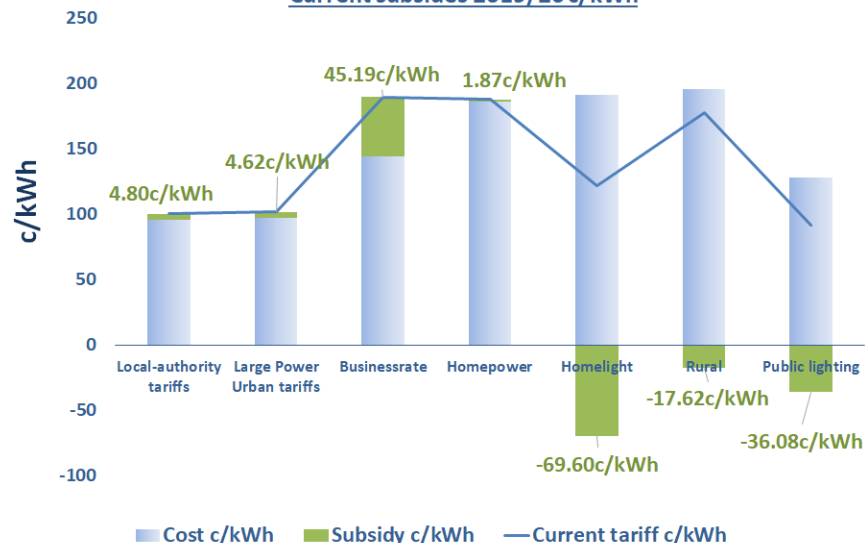
- There is no national directive, rule or guideline on electricity subsidies except for the policy positions in the EPP ([EPP policy positions on subsidies](#)) and the Nersa 2005 subsidy framework (status of the latter not known)
- Most subsidies are from legacy historical decisions, such as the Government's decision in the 1980's to cross-subsidise rural electrification (the electrification and rural subsidy)
- Section 16 of the ERA states that Nersa may permit certain level of cross subsidies
- Nersa has also at its discretion determined subsidies over the years such as the lower tariff increases to the Homelight tariffs which placed an additional burden on Eskom's large power non-munic tariffs (the affordability subsidy charge).
- Eskom has no mandate to make changes to socio-economic subsidies

The subsidies in electricity tariffs (where the tariff is higher of lower than cost)

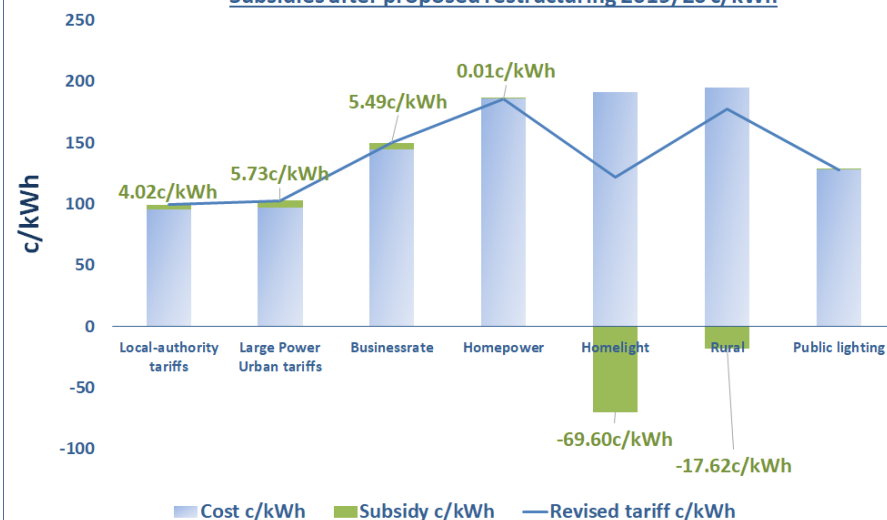
- Are within a tariff and based on structure (intra-tariff subsidies)
 - Structural or based on pooling of costs
- This can only be corrected once a tariff is redesigned
- The proposals in this retail plan have reduced some of the intra-tariff subsidies by aligning the charges with cost e.g.
 - Businessrate network charges
 - Reducing the LV subsidy paid by the urban large power tariffs by increasing the LV and MV network charges
- Are for affordability socio-economic reasons (inter-tariff subsidies for usage, network and connection cost)
 - Where the tariff category at a whole receives a subsidy and other tariffs pay these subsidies
 - These subsidies being paid are more transparent, but for the receiving tariffs it tends to be hidden
 - The tariffs receiving subsidies are the rural tariffs (Landrate, Ruraflex and Nightsave Rural) and the Homelight tariffs
- The overall R value level of subsidies to the subsidised rural and Homelight tariffs remains the same in this plan, but changes have been made structurally within tariff categories.
- The subsidy charges (ERS and Affordability subsidy) in this plan have reduced due to the updating of the rates by the cost to serve study

Subsidies current vs revised

Current subsidies 2019/20 c/kWh



Subsidies after proposed restructuring 2019/20 c/kWh



Current subsidies (2019/20 R value)	Cost Rm	Current tariff Rm	Current subsidy Rm	Percentage
Local authority tariffs	R 81 827	R 86 149	R 4 322	5%
Large power user tariffs	R 75 952	R 79 554	R 3 602	5%
Businessrate	R 1 541	R 2 022	R 482	24%
Homepower	R 2 700	R 2 727	R 27	1%
Homelight	R 17 287	R 10 999	-R 6 289	-57%
Rural	R 20 806	R 18 931	-R 1 875	-10%
Public lighting	R 276	R 203	-R 73	-36%

Revised subsidies (2019/20 R value)	Cost Rm	Revised tariff Rm	Revised subsidy Rm	Percentage
Local authority tariffs	R 81 827	R 85 464	R 3 637	4%
Large power user tariffs	R 75 952	R 80 426	R 4 474	6%
Businessrate	R 1 541	R 1 599	R 59	4%
Homepower	R 2 700	R 2 700	R 0	0%
Homelight	R 17 287	R 10 999	-R 6 289	-57%
Rural	R 20 806	R 18 931	-R 1 875	-10%
Public lighting	R 276	R 276	R 0	0%

Impacts for all tariffs



Impact of all restructured tariffs (2019/20 R value)

	CTS allocated allowed costs Rm.	Current tariff revenue Rm.	Diff current tariff revenue and cost	Restructured tariff revenue Rm	Difference new tariff revenue and cost Rm.	Revised subsidy c/kWh	% change in revenue due to restructuring	Difference in revenue Rm. due to restructuring
Total all tariffs	R 200 582	R 200 585	R 3	R 200 580	-R 2	(0.00)	0.00%	-R 5
Local-authority tariffs	R 82 257	R 86 324	R 4 068	R 85 702	R 3 445	4.01	-0.72%	-R 623
Municflex	R 81 827	R 85 935	R 4 107	R 85 269	R 3 441	4.02	-0.78%	-R 666
Municrate	R 192	R 215	R 22	R 196	R 4	3.78	-8.72%	-R 19
Public Lighting munic	R 237	R 175	-R 62	R 237	R 0	0.00	35.50%	R 62
Urban tariffs non-local-authority	R 77 493	R 81 576	R 4 083	R 82 025	R 4 532	5.73	0.55%	R 449
Megaflex	R 65 651	R 68 896	R 3 246	R 69 559	R 3 908	5.62	0.96%	R 663
Nightsave Large	R 1 959	R 2 188	R 229	R 2 209	R 251	15.22	0.97%	R 21
Nightsave Small	R 797	R 838	R 41	R 904	R 107	17.18	7.89%	R 66
Miniflex	R 4 232	R 4 111	-R 122	R 4 275	R 43	1.27	4.00%	R 164
Transflex 1	R 2 831	R 2 996	R 165	R 2 975	R 145	5.88	-0.69%	-R 21
Transflex 2	R 482	R 524	R 42	R 503	R 20	6.34	-4.07%	-R 21
Businessrate	R 1 541	R 2 022	R 482	R 1 599	R 59	5.49	-20.92%	-R 423
Rural tariffs non-local-authority	R 20 806	R 18 931	-R 1 875	R 18 931	-R 1 875	(17.62)	0.00%	R 0
Ruraflex	R 7 782	R 6 306	-R 1 477	R 6 574	-R 1 208	(25.14)	4.25%	R 268
Nightsave rural	R 2 550	R 2 628	R 78	R 2 360	-R 190	(12.15)	-10.20%	-R 268
Landrate & Landlight	R 10 474	R 9 997	-R 476	R 9 997	-R 476	(11.16)	0.00%	R 0
Residential tariffs non-local-authority	R 19 988	R 13 726	-R 6 262	R 13 699	-R 6 289	(59.98)	-0.20%	-R 27
Homepower	R 2 700	R 2 727	R 27	R 2 700	R 0	0.01	-0.99%	-R 27
Homelight 20A	R 10 203	R 6 280	-R 3 923	R 6 280	-R 3 923	(70.49)	0.00%	R 0
Homelight 60A	R 7 084	R 4 719	-R 2 366	R 4 719	-R 2 366	(68.17)	0.00%	R 0
Public lighting non-local-authority	R 39	R 28	-R 11	R 39	R 0	0.18	39.38%	R 11
Public Lighting All Night	R 38	R 27	-R 11	R 38	R 0	(0.00)	40.94%	R 11
Public Lighting Urban Fixed	R 1.14	R 1.21	R 0.07	R 1.14	R 0.00	(0.01)	-5.69%	R 0
Public Lighting 24 Hours	R 0.16	R 0.06	-R 0.10	R 0.22	R 0.06	107.31	242.04%	R 0
Generator TUoS and DUoS revenue	R 0.00	R 0.00	R 0.00	R 184.00	R 0.00	0.00	0.00%	R 184

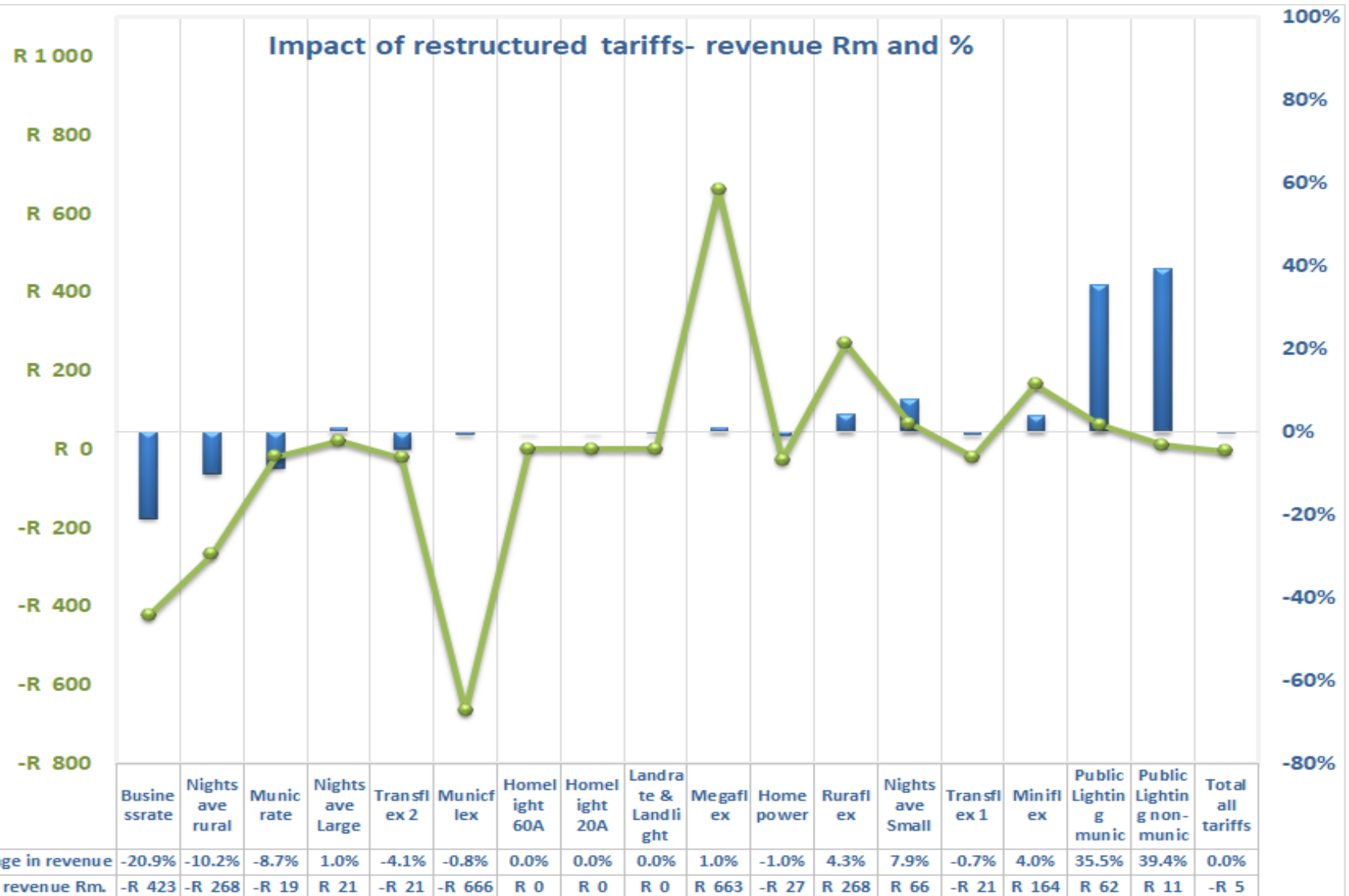
Allocated allowed
costs

Difference between
cost and current tariff
revenue

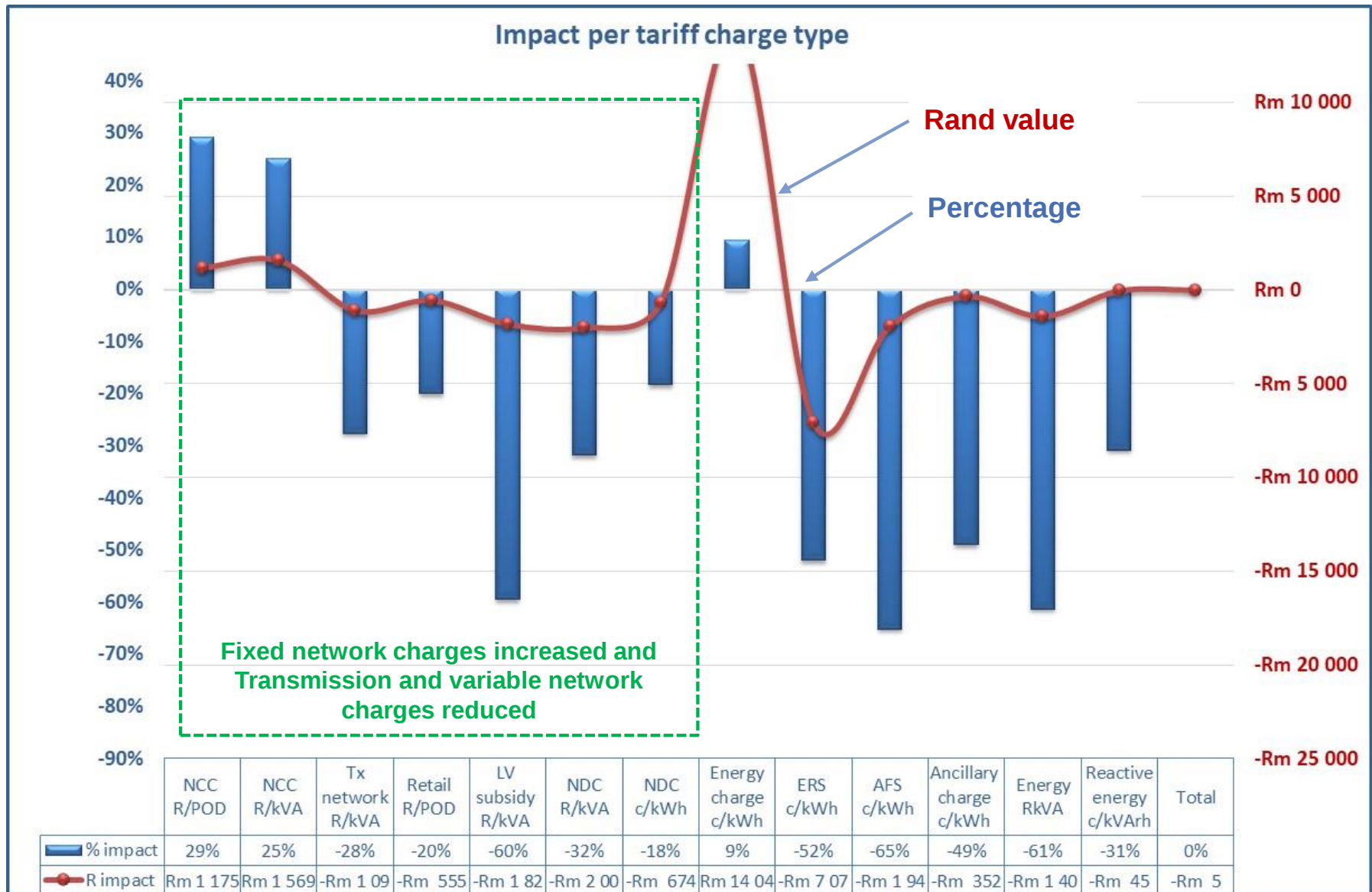
Percentage
change due to
restructuring

Rand value
impact

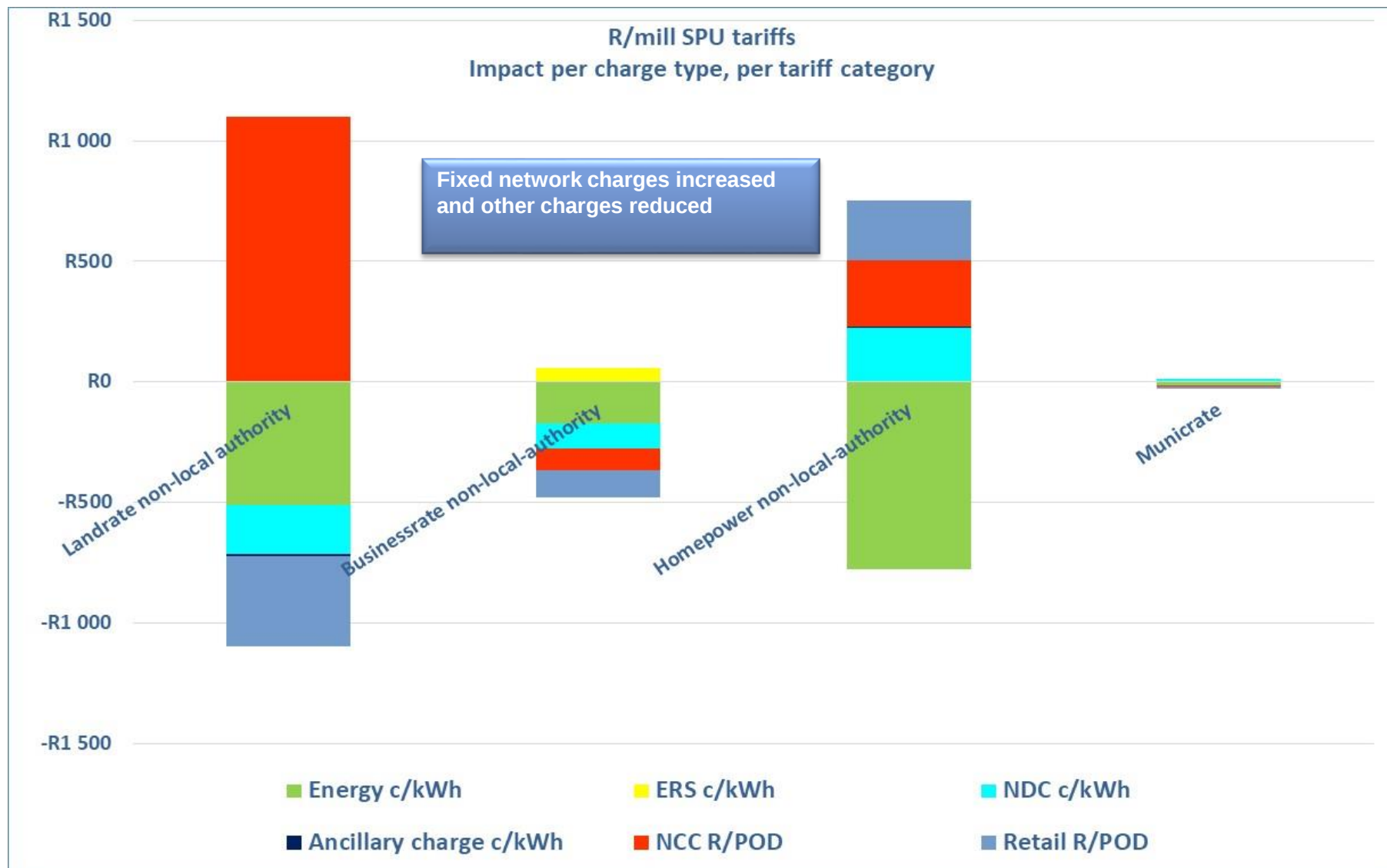
Impact of all restructured tariffs (2019/20 R value)



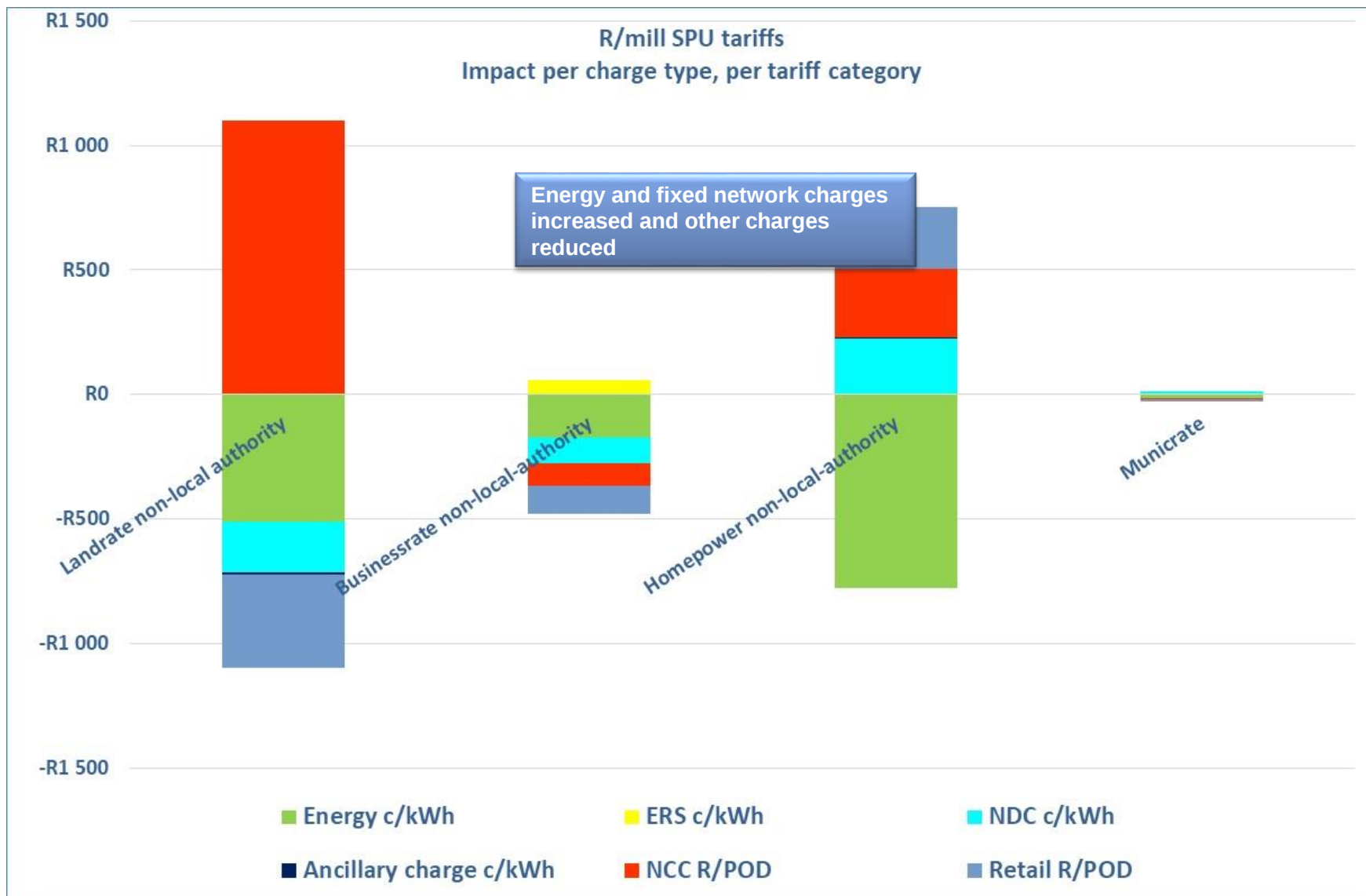
% impact per tariff charge type – Eskom total



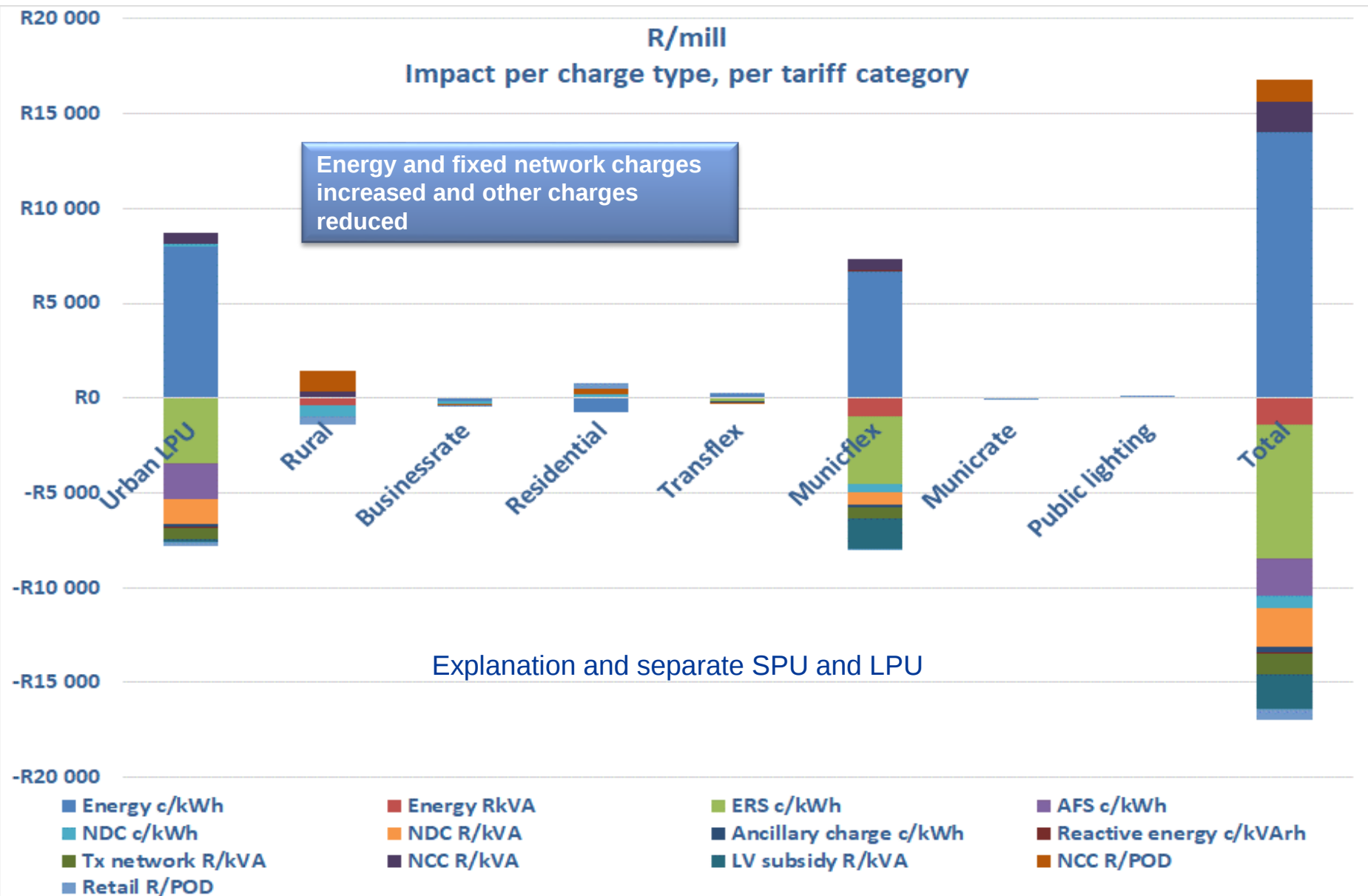
R Impact per tariff charge type per tariff category – SPU tariffs



R Impact per tariff charge type per tariff category – LPU tariffs



R Impact per tariff charge type per tariff category – Eskom total



Overall expected impacts (1)

- Updating rates with the CTS, in particular the increase in energy costs by 14% relative to other charges.
 - This corrects the misalignment caused by applying average increases to all tariffs instead of increases per Eskom division. It also highlights that the current energy charges are lower than they ought to be.
- The changes to the TOU periods and rates. This impact per customer will largely depend on load profile through the year and response to the TOU changes.
 - Reduced winter rates result in high consumers paying less in winter (and vice versa).
 - High summer peak users will pay more.
- It is not possible to determine the impact of the TOU response, as this response is not known at the time of doing the tariff design.
 - It is expected that there will be a response based on research results and history, but this may only happen over time and not immediately. This response (whether positive or negative for Eskom), like all volume responses will be treated in terms of NERSA RCA rules.
- Increasing the fixed-charge components will result in lower average network prices for higher load factor customers (and vice versa).
- A reduction in the retail costs will result in lower service and administration charges.
 - Charging the service charge per POD and not per account may negatively impacts customers with many linked PODs to one account.

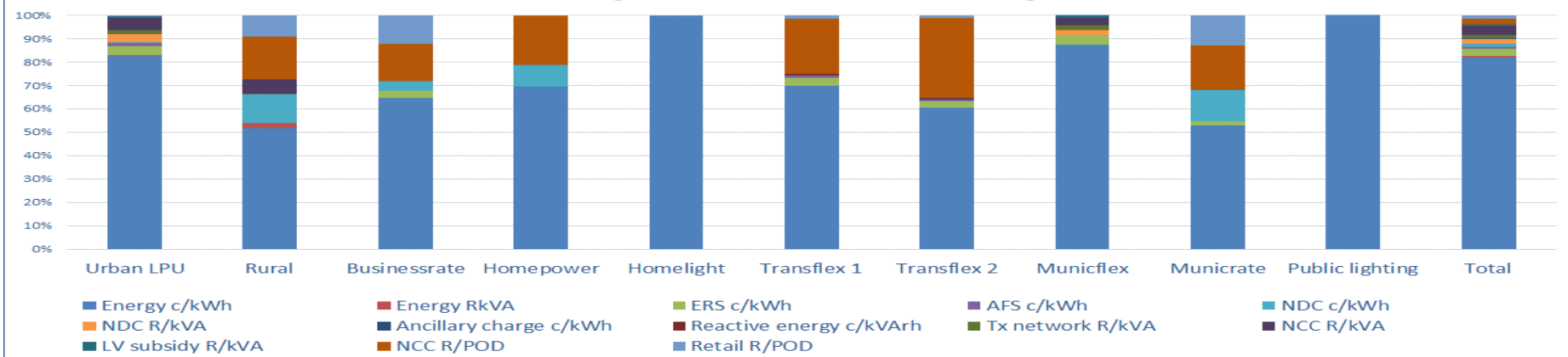
Overall expected impacts (2)

- Splitting of the LV subsidy charge between non-local-authority tariffs and local-authority tariffs resulted in the contribution to the low- and medium-voltage subsidy for the non-local-authority tariffs to be increased, as there is more volume in this category.
 - Local-authority tariffs now only contribute to low- and medium-voltage subsidies in the local-authority tariff pool.
- The ERS charge and affordability subsidy charge have also decreased, this is mainly due to the rates being updated based on the CTS.
 - Currently these subsidy charges are overstated.
- As per NERSA's requirement, the local-authority tariffs have been based on the CTS and combined for both rural and urban per LPU tariff category and per SPU tariff category.
 - This has resulted in an average decrease for these tariffs, except for the Public Lighting tariffs.
- Public lighting tariffs see a significant increase, resulting from updating the tariffs with the CTS study.
 - This tariff has been under-recovering against costs significantly and is not one of those identified as receiving subsidies.
 - This tariff currently barely recovers energy costs.
- Nightsave Urban Large and Nightsave Urban Small were aligned to make the energy demand charges the same.
 - Both tariffs see an increase due to updating with the CTS, with Nightsave Small having a larger negative impact.

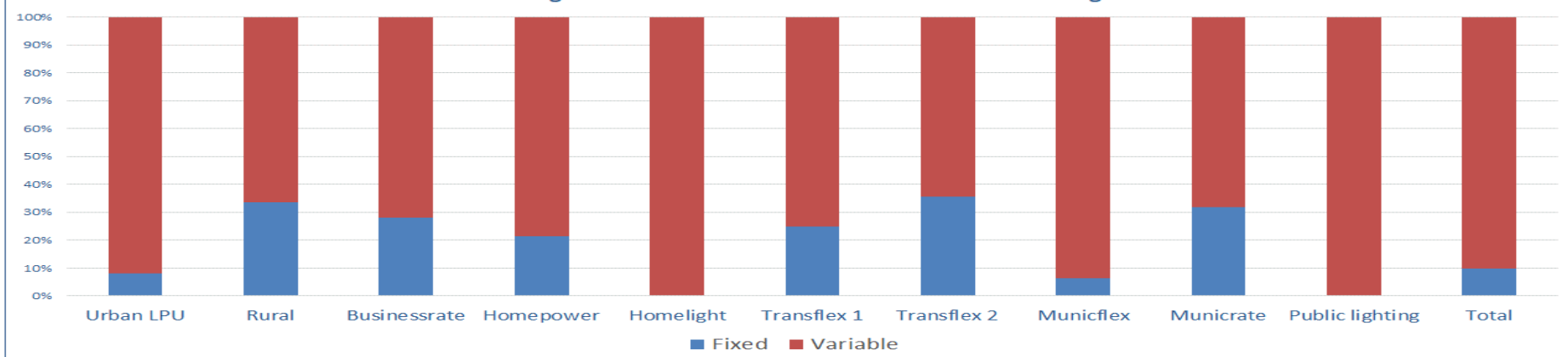
- Businessrate sees a big reduction due to updating with the CTS.
 - This tariff category now contributes to the ERS charge and affordability subsidy charge in order to align with the other commercial LPU tariffs paying this contribution.
- For the Homelight tariffs, removing IBT has a small negative impact on very low-consumption customers and a positive impact on higher-consumption customers.
- For Landrate, some rebalancing has been done between tariff categories, firstly, based on cost and, secondly, based on applying subsidies.
 - Landrate 2 and 3 see a negative impact, based on design to reduce the significant subsidies in these categories, and Landrate 1 and 4 see a reduction. The level of subsidies remains the same overall.
- For Ruraflex and Nightsave Rural, the network charges have been aligned (made the same).
 - This, together with the cost-reflective increase in energy charges, has resulted in Nightsave Rural seeing a reduction and Ruraflex an increase. The level of subsidies, however, remains the same overall.
- For Homepower, per supply size category, the impact is due to updating rates with the CTS study.
 - Homepower, on average, sees a reduction due to using costs as the basis, with no overall subsidy.
 - Removing IBT and introducing a more cost-reflective R/day charge results in lower-consumption customers paying more (and vice versa).
- **The tariff charges will be updated based on the Nersa decision for approved changes, and also as part of the price increase process to 20/21 R values**

Breakdown of fixed and variable charges based on revised tariffs

Percentage contribution to different tariff charges



Percentage contribution to fixed versus variable tariff charges



The ratio of fixed charges compared to variable charges per Eskom tariff type is relatively small, compared to actual fixed costs

Fixed charges will make up a bigger percentage of total tariff charges where fixed costs are high (such as for the rural tariffs) and/or where the load factor is low.

Challenges in tariffs in a future model – cost reflectivity and subsidies

- Tariff structures in the EDI do not always provide the correct economic signal i.e. fixed network costs recovered through c/kWh charges.
 - This can have a detrimental impact on distribution businesses – particularly in the light of embedded generation – where grid services are still provided for import and export and for standby – but where there is reduced sales and therefore reduced revenue
 - In future energy costs would also have to be unbundled into fixed capacity (the infrastructure needed to have generation capacity available) charges and variable energy related (typically fuel and water).
 - Customers with embedded generation get subsidised by those without if tariff structures not corrected
 - Reduces sales and not demand
 - It has been found in the USA that after embedded generation installation, **customers reduced their monthly energy consumption by 49%** in the summer, but only reduced their **peak demand by 4.9%** during the same months, resulting in a significantly lower load factor*
- Also no consistency in tariff structures and rates – there is a need for a national tariff framework.
- Also no national cost of supply study framework – needed to determine the level of cross-subsidisation.
- There is no national cross-subsidy framework – who should be subsidised, who should pay and how should it be funded?

- Annual updating of different rates due to Eskom unbundled and separate divisional increases – no longer a single average increase applied to all rates;
- Further changes to the TOU rates and periods to accommodate managing a changing system profile;
- Restructuring the energy charges into fixed and variable components through the introduction of payment for energy capacity;
- Further rationalisation of tariffs by removing Miniflex and Nightsave tariff versions as options (that is, only having Megaflex for urban tariffs);
- Further rebalancing between fixed and variable network charges;
- Further development regarding generator use-of-system charges and offset rates;
- Moving to making TOU mandatory for all new three-phase SPU connections, and
- Introducing of flexible short-term tariff options to address customer needs and Eskom operational requirements.

1. Tariffs updated based on the cost-to-serve study and will include pricing signals
 - Nersa requirement to motivate changes based on cost of supply
 - Signals are not always based on costs, but to incentivise customer response so as to create efficiencies and reduce costs
2. Tariffs modernised to reflect changing technology environment
 - Reflecting fixed costs more accurately
 - Recovering the cost of providing standby capacity (grid and energy)
3. Municipal tariffs separated and reduced based on cost-to-serve study
 - Municipal contribution to subsidies reduced
4. IBT structure removed for residential tariffs
5. Some customer will pay more and others less
 - Not possible to have zero impacts when updating with cost to serve
6. All rates will be updated per the price increase process to the year of application

Eskom's 2020_21 retail tariff plan

